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WHICH ELECTRICITY MARKET DESIGN TO ENCOURAGE THE DEVELOPMENT OF DEMAND RESPONSE?

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Abstract

Demand response is a cornerstone problem in electricity markets under climate change constraint. Most liberalized electricity markets have a poor track record at encouraging the deployment of smart meters and the development of demand response. In Europe, different models are considered for demand response, from a development under a regulated regime to a development under competitive perspectives. In this paper, focusing on demand response and smart metering for mid-size and small consumers, we investigate which types of market signals should be sent to demand manager to see demand response emerge as a competitive activity. Using data from the French power system over the last 8 years, we compare the possible market design options to allow demand response to develop. Our simulations demonstrate that with the current market rules, demand response is not a profitable activity in the French electricity industry. Introducing a reserve and/or capacity remuneration could bring additional revenues to demand response providers and improve incentives to put in place demand response programs in a market environment.

Keywords

Market Design; Demand Response; Capacity Market.

1. Introduction*

Physical equilibrium between generation and load in real-time has always been a key issue for the power system operator because this energy cannot be stored economically on a large scale. Without storage, equilibrium in real-time has been traditionally manage thanks to generation. Until recently, demand response[1] was little used to balance power system because of there was no real time metering infrastructure.

The main interest of demand response is that it participates in balancing the power system for some hundreds of hours a year in the same way as does the peak generation. Demand response so raises a new attention because most liberalised power systems with an 'energy only' market are characterised by a deficit of investment in peaking units, caused by a lack of revenue. This so-called "missing money" problem have now been widely studied (see Joskow (2007, 2008) Cramton and Stoft (2006) and Finon and Pignon (2008). for an in-depth survey). The solutions to address the peaking unit missing money issue include a range of market arrangements, for instance the introduction of a strategic reserve of power plants controlled by the system operator, long-term capacity contracts, capacity payments or capacity markets.

But assuming that demand response can be a substitute for peaking generation invites us to analyse the potential impact of the missing money problem on demand response. To test the existence of a missing money problem for demand response, we will use empirical data from the French power market over the past eight years. Our numerical simulations show that the 'missing money' issue in current power markets is very likely to affect demand response aggregators and to make the recovery of the upfront investment in smart metering infrastructure difficult to recoup through market revenues. We then wonder which market design could foster the development of demand response toward small (domestic and tertiary) consumers and, that is to say which types of market signals should be send to a demand manager to see demand response emerge as a competitive activity solving the missing money issue.

The paper is structured as follows: we first specify the characteristics that distinguish demand response from peak generation. Then, we highlight the problem of compensation that a demand response program would experience on a power market. At last we study the matching between the incentive mechanisms implemented to ensure sufficient peak generation investment and the specificities of demand response. We conclude about the ability of pure liberalized market solution to provide sufficient incentives for the development of demand response.

2. The parallel between a demand response program and a peak generator

A demand response program and a peak generator face a number of similar issues, including the "missing money" problem observed in most liberalized power markets. But there are also a number of significant differences. In this section we demonstrate that both of them are important to take into account when evaluating the impact of the missing money issue on the profitability of a demand response program.

* The views expressed are those of the authors only.

1 Demand response consists in reducing load level of some consumers for some time when the price of electricity reaches a high level (from several hundreds of euros). This reduction can be directly controlled by the demand manager or otherwise be left entirely to the discretion of the consumer informed about the price of electricity (Piette et al., 2004).

2.1 Similarities between a demand response program and a peak generator

A demand response program can be used to replace a peak generator in a limited number of situations only. In order to determine the uses where a peak generator and a demand response program are substitute, we review the alternative uses of a peak generator and discuss the extent to which a demand response program can provide the equivalent services.

First, a peak generator is scheduled day-ahead to supply energy only during the peak demand hours. This is because a peak generator has higher marginal cost than other units and it is the last type of generation units to be planned and started up to supply energy to load. The fact that a peaking generator is dispatched after all other units to meet the residual demand makes the revenues of a peaking generator very hard to predict and very uncertain. An investment into a peak generator is thus very risky because it depends on the level of power demand that, itself, depends on extreme weather conditions. For a power system that experiences high levels of demand during the heating season, a very cold year will mean that the peak generator will run for a large number of hours. Contrarily, a warm year will mean that the peak generator may not run at all, being then unable to pay back the annuity of its investment during this year[2].

A peak generator is also very useful to balance the power system in real time (providing ancillary services) or close to real time (realising adjustments). These second and third use of a peak generator are related to its characteristics of high flexibility and short start-up time. This feature is very valuable in real time to balance generation and load in an industry where stocks are impossible. Indeed, the time to react to an imbalance in real time is short, from seconds to a maximum of 15 minutes[3]. A peak generator is adapted to contribute to the power balance within this time period because it is very flexible once started-up and to be started up quickly. Indeed, peak generators or hydro generators with dams are the principal generators to be used to act in such a short delay[4].

A demand response program can replace a peak generator only for two of the uses listed above, on a daily basis and for adjustments. A load curtailment can be planned day-ahead when load is high to help and balance supply and demand. A load curtailment can be activated in real time to compensate imbalances.

However, the differences between a demand response program and a peak generator, detailed hereafter, make it impossible for a demand response program to provide ancillary services.

2.2 Differences between a demand response program and a peak generator

A demand response program and a peak generator are not pure substitutes for four reasons. First, a load curtailment can only happen if demand was planned and anticipated with sufficient notice. For the moment, curtailment in the residential sector was mainly planned on energy uses with inertia such as the production of cold or heat to avoid any disturbances of the consumers. However, these energy uses with inertia are only active when demand is high[5].

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[2] The same reasoning applies in a similar manner for power system that experiences high levels of demand during the warm season like in the USA due to an intensive use of air conditioning.

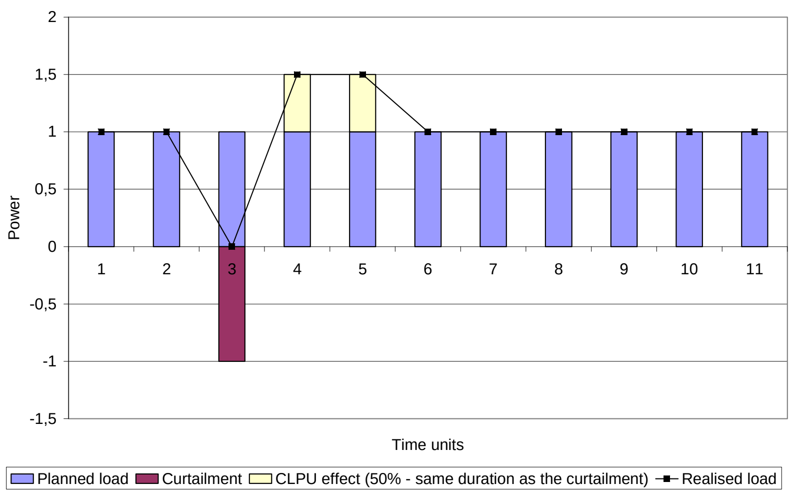
[3] The automatic ancillary services must react in seconds or minutes during fifteen to twenty minutes after the disturbance. After more than fifteen minutes of imbalances, the capacity of ancillary services must be restored so that the power system can support any new imbalances. This requires that a generator be started up (or that a demand response operator curtail load) in less than 15 minutes.

[4] The provision of ancillary services is generally risk-free because a part of the remuneration is associated to the availability of capacity. However, the activity of adjustment in real time implying starts-up is risky for a peak generator because its use depends on uncertain imbalances.

[5] Load is high when weather is hot for power systems with a lot of air conditioners or when weather is cold for power systems with a lot of electric heaters.

The second difference between a demand response program and a peak generator is the Cold Load Pick-Up (CLPU) effect. The CLPU is the additional energy and power temporarily needed to compensate the previous curtailment. The two main parameters of the CLPU effect are its size and its duration. These characteristics are essential to the profitability of a demand response operator. If the level of the CLPU effect is smaller than 100%, any demand curtailment saves energy and is also likely to induce money savings[6]. The smaller the CLPU effect is, the higher the money savings are. Figure 1 illustrates a CLPU effect of 100% (which means the curtailment does not modify, neither increasing nor decreasing, the energy consumption) and lasting twice the time of the curtailment.[7]

Figure 1 Illustration of the CLPU effect appearing after a load curtailment



The third specificity of demand response program compared to peak generation units is that it is an intermediated tool of management not a direct decision taken by a company. This characteristics makes the business model complex for the deployment of demand response (Albadi & El-Saadany, 2008; EUDEEP business model 1). In most of the demand response programs, it is not the demand manager that directly curtails its customers, he just sends them a price signal telling them that they should curtail. They then have to react to price signals within the limits of their other constraints. Thus, it is difficult for a demand manager to predict and commit to a response rate among its customers and therefore the real capacity of its demand response program.

Some operators then choose to sell controlled demand response program. The operator takes care of the direct curtailment of its customers in a way that they do not feel any disturbance. This solution has however two drawbacks. Firstly, the operating costs of the demand manager are much higher than in the previous solution, because of the establishment and operation of a demand-side management dispatching, which will manage the curtailment of all customers. Then, even with a controlled demand response program, the consumer always has the right to overrule the order of curtailment and to continue to consume electricity. The rate of response from consumers to a curtailment order will never be 100%, and it may be may vary on a wide range. It was then experienced between 9% and 53% in the North East of the USA (Cappers, Goldman, & Kathan, 2009).

Lastly, there is also the issue of entry and exit of customers because demand response program is a commercial activity that caters to residential or tertiary customers. Therefore, the demand response capacity of an operator may vary over time depending on the dynamics of its customer base.

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6 Conversely, any CLPU effect above 100% means that any demand curtailment induces a global increase in energy consumption and higher energy expenses.

7 See Agneholm (1999) for a quite broad characterization of the CLPU effect.

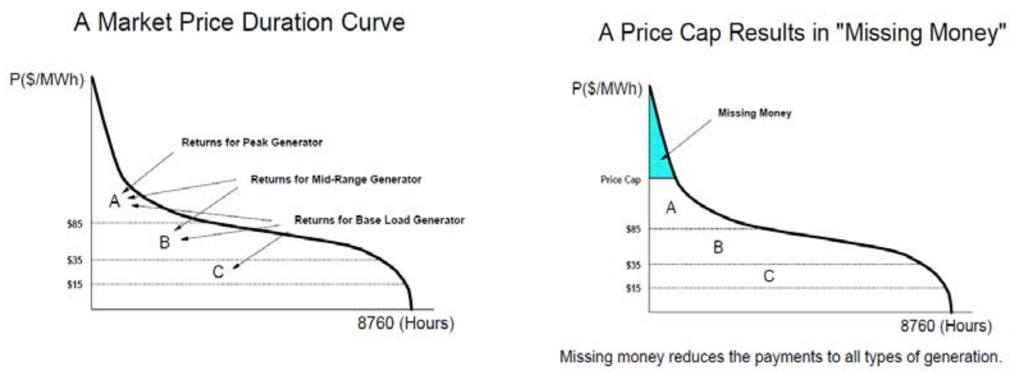
Considering the intermediated nature of demand response for small and medium size consumers, it may be difficult for such a demand response program to provide ancillary services when needed. The provision of secondary reserves implies that the respondent receives a signal displayed the TSO itself over a dedicated telecommunication infrastructure. If demand response provided secondary reserves, this would impose that this dedicated infrastructure be extended toward. Besides, the response time typically required for ancillary services providers seems hardly compatible with the intermediation needed in demand response program. And ancillary services being the first reaction of power system to hazard, its limited controllability induces a de facto limited participation in the provision of ancillary services.

2.3 A "missing money" issue?

At the time of renewing or extending peak generation units, several liberalized power markets have experienced low level of investment. This was due to the insufficient revenue these investors were receiving from the market prices and to the risk they perceived from them since they are paid for hundreds of hours in a year only and with great variations from a year to another (Joskow, 2008). Several hours in a year, the market is so tight that the spot price soars and blithely exceeds several thousand euros/MWh (Joskow, 2008). This scarcity rent is very important for the peak generator because it allows them to cover its investment costs during its few hours of operation. In the extreme case where demand is greater than production, prices even reached a threshold at which some consumers prefer to disappear spontaneously rather than to pay for the asked price. This threshold is generally noted "VoLL" for Value of Lost Load.

Many regulators however see this very high price as a market failure or as a politically unbearable price situation. To solve this problem, some regulators set a price cap that the market price can never exceed, as shown on figure 2. This price cap then limits the income generated by the peak generator and reduces the incentive to invest in such peaking units. Other things equal, the price cap will have the same effect for the remuneration of a demand response operator that is only remunerated through the energy markets.

Figure 2 Missing money emerging from price cap (Hogan, 2007)



All these considerations lead to the identification of a lack of revenue, the so called "missing money" for any facilities (peak generator or demand response) acting during the peak hours. A classical solution to fill the gap is to pay them for their availability and not only for the energy production or curtailment. A peak generator would then be paid for its availability during the peak hours and for its production when dispatched. And a demand response program would then be paid for its availability during the peak hours and for the effective undergone curtailment. According to the solutions chosen in the national market designs, peak generator had more or less difficulties to recover its investment cost.

However, given the four characteristics of a demand response program (appearance only when demand is high, CLPU effect, control and dynamics of customer base), a market design adapted to the development of peak generation may not necessarily be adequate for the deployment of demand response.

3. The need to pay a demand response program for availability

The implementation costs of demand response for the big industrial consumers[8] and the big tertiary consumers[9] are quite low and adapted to load management. Nevertheless, for the small tertiary and domestic consumers that stand for the biggest possibility for demand response[10], the historical metering devices are not adapted[11]. The implementation of demand response program that can follow the hourly variations of electricity market price then requires these old metering devices to be replaced and a demand control center to be developed to aggregate the individual demand response into demand response volume big enough to be tradable on the marketplace (Albadi & El-Saadany, 2008; Faruqui & Sergici, 2009).

This new infrastructure requires a large upfront investment with uncertainty on the costs and returns (Haney, Jamasb and Pollitt 2009). For instance in France, the “Linky” program to deploy smart meters is evaluated between 4 and 8 billion euros for the installation of 30 million new intelligent metering devices[12]. This new infrastructure being brand new, to our knowledge, no detailed information is available to evaluate the extent of economies of scale and so the competitive or regulatory nature of demand response program.

In this section we evaluate the potential missing money problem for Demand Response. First, we recall the two main revenue sources for a peak generator, either the spot day-ahead market or the balancing market. Second, we evaluate the revenue that can be expected from these markets and we extract general conclusions using data from the French case.

3.1 Two markets to buy and sell electricity

Liberalised power markets actually consist in a sequence of closely connected markets with different time horizons, from forward markets years ahead to real time markets. A producer can choose to sell its electricity mainly on two different markets: a market said "Spot" or day-ahead market, and a balancing market used to compensate for real time imbalances between generation and load (Saguan et al., 2009).

In France, the spot day-ahead market is run by the Power Exchange “EPEXSpot”[13]. Each day at 11:00, a market player may submit voluntary offers on this exchange: for every hour day-ahead, he may offer a buy or sale bid. Intraday trade is also possible on EPEXSpot. But these exchanges represent a much smaller volume than the day-ahead one. As for the balancing market, it is a tool for

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8 They generally stand for 30% of total consumption.

9 The main function of a Building Management System is to manage the environment within the building (cooling, heating, air distribution, lighting...) to obtain the desired temperature, carbon dioxide levels, humidity, brightness, etc.

10 They jointly stand for the remaining 70% of total consumption.

11 At best, these metering devices distinguish two to three ranges of several hours in a day.

12 To widen the range of possible cost, a French independent demand response aggregator pretends that his investment costs are 20 times smaller than the investment cost of a peaker.

13 Previously called PowerNext until 2009.

the Transmission System Operator (TSO) to ensure the balance of the power system in real time. Each player in this market bids upward or downward. In case of system imbalance, the TSO asks for the balancing market and selects some bids to balance back generation and load. The balancing market is also completed by the ancillary services (primary and secondary reserves) that allow rapid automatic balancing. The provision of ancillary services can be regulated or organised as a market. The remuneration that generators receive from the provision of ancillary services is quite small compared to the remuneration provided by the day-ahead and real time markets.

For instance, in France, the average yearly cost of ancillary services is less than 1 €/MWh (with an annual cost around 300 million € to serve around 450 million MWh) compared to the average peak spot price of electricity close to 60€/MWh on EPEXSpot[14] (CRE, 2010).

These day-ahead and real time markets are in France and in most of the European countries the main sources of remuneration for different electricity generators, after the bilateral market. A generator with a winning bid on the Spot Market is paid the spot price. A generator with a winning bid on the balancing market is generally paid his bid price. Let us now see the distinct impact of these two systems of remuneration on a demand response program.[15]

3.2 The need to remunerate a demand response program for its availability

Considering the similarities and differences between a demand response program and a peak generator, the objective of this section is to evaluate whether a demand response program would be profitable in an "energy-only" market context transposing previous analyses of this problem for peak generators on the case of a demand response program.

3.2.1 Cost estimations

In order to tackle our problem, we consider two polar scenarios for the estimation of the different costs: the optimistic scenario is built using the most positive data set and the pessimistic scenario is conversely calculated taking into account the less enthusiastic assessments.

In the optimistic scenario, we use the following estimations. The cost of a demand response program can be estimated after the costs of the Linky project in France (estimated at four billion € by ERDF)[16]. We rely on other optimistic assumptions with a long lifetime for meters (40 years), a discount rate for a regulated company (8%) and a significant potential for demand side-management capacity (13 GW).

In the pessimistic scenario, we use the following estimations. The cost of the demand response program can be estimated from the FNCCR[17] evaluation of the Linky projects with 8 billion euros. We rely on other pessimistic assumptions with a short lifetime for meters (20 years – due to the innovative and fragile feature of the used technology), a low and high market discount rate (respectively 15% and 20% according to the anticipated risk level of the investment) and a potential for demand side-management capacity limited to its level before the reform (6 GW).[18]

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[14] Source: CRE, 2010. Observatoire du marché de gros de l'électricité. 1er trimester 2010.

[15] Transmission constraints are integrated in the day-ahead or real time prices paid to the winning bids.

[16] An independent demand response operator estimates that his investment cost is even smaller, until twenty times less than the investment cost of a peaker, that is to say around 3 k€/MW.

[17] The FNCCR is the National Federation of Local Authorities Licensors and Boards.

[18] The optimistic and pessimistic cost levels for the installation of 30 million smart meters in France are consistent with standard costs for these technologies (Deconinck, 2008).

These assumptions lead to an annualised cost of 335 million euros for the optimistic scenario and between 1267 and 1636 million euros for the pessimistic scenarios.

Table 1 summarises our assumptions and results of our calculation.

Table 1 Assumptions of the optimistic and pessimistic scenarios for the calculation of the investment cost of a demand response program

Scenarios	Costs (M€)	Lifetime for meters (years)	Discount rate (%)	Annualised investment cost (M€)	Demand response capacity (GW)	Average annualised investment cost (k€/MW)
Optimistic	4 000	40	8	335	13	26
Pessimistic	8 000	20	15	1267	6	211
			20	1636	6	273

We then compared these cost with the benefit that demand response could generate at maximum from the market. For a matter of simplicity, we suppose that the introduction of demand response would not depreciate price. Besides we suppose that the potential of demand response is fully used each year. Both simplifications lead to optimistic evaluations since in reality the use of full capacity of demand response may depend on the load level and may impact price level.

Even if no information is available to our knowledge about the variable cost of demand response for a demand response operator, it must not be neglected. When the consumer has contracted a fixed price rate, the demand response operator must pay the consumer to award him for his efforts of curtailment (RTE, 2011). Besides, in the case of a demand curtailment in real time, the generator must also be compensated for its planned but unsupplied energy (see Glachant & Perez, 2010 for references).

A last uncertainty about demand response is the cold load pick-up effect. To avoid any case by case study, we will assume that the duration of the CLPU effect is equal to the duration of the related demand curtailment. We will then consider three levels of CLPU effect, first 0% (no CLPU effect), 50% and 100%.

3.2.2 Estimations of the revenue of a demand response operator

A demand response operator can cumulate to some extent the revenue from both the day-ahead market and the real time market, limiting thereby the problem of missing money. In reality, the demand response operator would face uncertainty about the real time prices while wondering day-ahead whether to bid on the spot market or to wait and possibly bid on the real time market. In order to evaluate the potential revenue from such a strategy, we assume that the demand response operator perfectly anticipates the real time prices day-ahead. The demand response operator is then able to make perfect arbitrage between the day-ahead market and the real time market. In particular, when the real time price is lower than the maximum day-ahead price at peak time, he would decide to act in the day-ahead market and not in the real time market at that moment[19].

The demand response operator is paid on the day-ahead market the maximum hourly price when it is higher than the real time price at that hour minus the minimum hourly price during the following off-peak period. He is also paid on the real time market his bid price when it is lower than the marginal price minus the compensation of the consumers that he curtails[20]. The balancing responsible

[19] Or conversely the real time price is higher than the day-ahead price when the latter is maximum, he would decide to act in the real time market at that moment and search for the moment when the spot price is the second higher.

[20] He has to paid 50 €/MWh to the supplier in this case (see *supra*).

party whose perimeter includes the demand response operator must also bear an imbalance cost due to the CLPU effect he pays at the upward imbalance price.

The optimised spot product we consider is similar to the one proposed by RTE (2011) in the framework of discussions about the characterisation of demand side response in the CURTE[21], the Comity of Users of the Electric Transmission Network, in order to calculate the marginal gross gain of a demand response operator between 2006 and 2008. RTE (2011) considers a theoretical product optimised at the daily scale. This product could be the result of an aggregation in the portfolio of a supplier. It is then less restrictive than a curtailment that would happen for a unique customer[22]. The studied product is a 1MW load curtailment activated 1 hour a day during the daily peak and with a CLPU effect occurring optimally during the off-peak time[23]. This product is remunerated by the spot price.

Considering these characteristics, we search for the price the demand response operator should bid in the real time market in order to optimise its total revenue. He cumulates the revenues collected on the real time market and on the day-ahead market. We have performed this calculus using data from the beginning of the French balancing market in summer 2003 to the end of 2010 and spot prices for the same period. Table 2 summarises the prices that would optimise the cumulated revenue of a demand response program arbitraging the real time and day-ahead markets with the different values of the CLPU effect.

Table 2 Prices optimising the revenue of a demand response program that arbitrages the real time market and the day-ahead market when the CLPU effect is respectively 0 %, 50 %, 100 %

Value of the CLPU effect	Price optimising the real time revenue of the demand response program	Optimised revenue between 2003 and 2010
0 %	83 €/MWh	314 k€/MW
50 %	83 €/MWh	280 k€/MW
100 %	289 €/MWh	158 k€/MW

With these prices, we obtain annual revenue ranging from 11,000 €/MW to 61,000 €/MW for the different levels of the CLPU effect, as summarized in table 3.

Table 3 Average revenue from the arbitrage between the day-ahead market and the real time market for a demand response program with different levels of the CLPU effect between 2003 and 2010

Average total revenue (k€/MW) from the arbitrage between the day-ahead market and the real time market for different levels of the CLPU effect			
Year	CLPU 0%	CLPU 50%	CLPU 100%
2003	22	16	13
2004	18	16	11
2005	39	35	22
2006	47	43	25
2007	37	35	26
2008	61	56	29
2009	47	42	20
2010	41	37	14

The three figures below illustrate the origin of the revenue, either from the day-ahead market or from the real time market respectively for the three considered values of the CLPU effect. They also allow

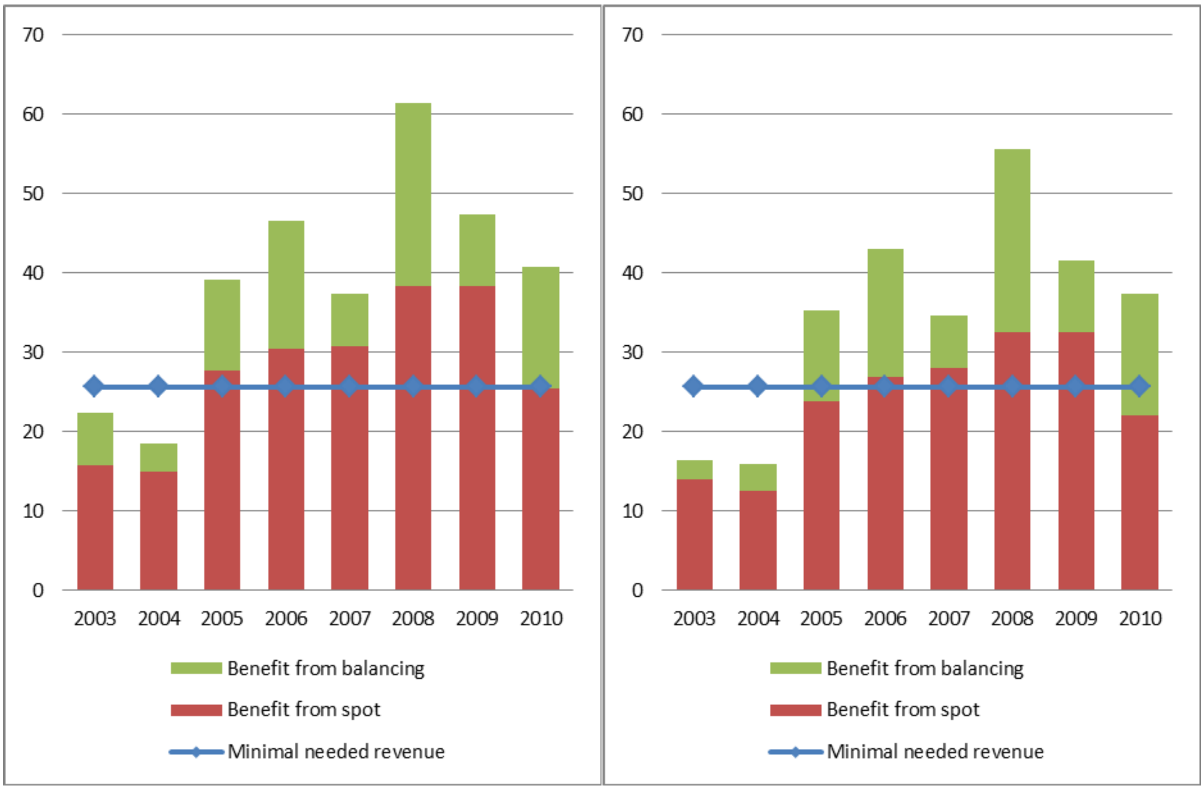
[21] In French, *Comité d'Utilisateurs du Réseau de Transport d'Electricité*.

[22] In this situation, the rebound effect would happen just after the curtailment period.

[23] RTE assumes the level of the CLPU effect to be 75%.

to compare for a demand response operator adopting this strategy with the minimum needed revenue, that is to say 26 k€/MW the minimum annualised investment cost of a demand response program we previously calculated.

Figures 3 and 4 - Comparison between the minimum annualised investment cost of a demand response program and its annual revenue from the arbitrage between the day-ahead and real time markets between 2003 and 2010 with a 0 % CLPU effect / a 50% CLPU effect



The analysis of the figures 3 and 4 shows that a demand response operator experiencing a CLPU effect below 50 % would have earned a revenue between 2005 and 2010 from the perfect arbitrage between the day-ahead market and the real time market above the minimum required level to avoid any problem of missing money.

This optimistic result should of course be tempered. We assume a perfect arbitrage between day-ahead and real time. This result encompasses risk for the business of any demand response operator because he may not perfectly manage his bid on the two markets on an hourly base in presence of uncertainties[24]. Besides, if his annual revenues are here higher than the minimum needed revenue, they are still far from the less pessimistic level of the annualised investment cost of a demand response operator (211 k€/MW as calculated in table 1) . The problem of missing money may then still remain with imperfect arbitrage between the day-ahead market and the real time market.

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[24] For instance, an operator can anticipate low revenue with quite low uncertainty from the day-ahead market hoping for higher but more uncertain revenue from the real time for the same hour.

4. Which solution to solve the missing money problem for a demand response program?

Electricity markets currently implement different tools to solve the missing money problem for peak generation. Some markets have implemented regulation-oriented mechanisms to remunerate peak generation while other regions have implemented market-oriented mechanisms to remunerate peak generation. Finon and Pignon (2008) distinguish four main types of solutions to compensate for the missing money problem: namely Strategic Reserves (detained by the system operator), Long Term Contract, Capacity Payment and Capacity Market. Table 4 illustrates the three last options (since the first one implies the vertical integration of peak generation with the system operator).

Table 4 Tools to solve the missing money problems and the countries

	Long term contracts	Capacity payment (whose variant with flexible price)	Capacity obligation and capacity market
Countries	Portugal Sweden, Norway, France, GB	Spain, Italy Argentina, Chile, Colombia, Peru,	USA regional markets: PJM, New York, New England

To evaluate the match between these different capacity mechanisms and the distinctive characteristics of demand response, the features of demand response program that distinguishes it from peak generation must then be taken into account. We will present the listed tools from the most integrated and regulated solutions to the more market-oriented ones. We will evaluate the matching between the above mentioned specificities of demand response program (in particular control and dynamics of the customer base) and the different solutions to missing money, i.e. long-term capacity contracts, the capacity payments and finally the capacity markets.

4.1.1 Demand response and long term contracts

The long-term contracts are contracts between the TSO and producer in which the producer agrees to make available to the TSO a certain amount of generation capacity at peak time (Finon & Pignon, 2008). When the TSO wants it, he may ask the generator to use all or part of the capacity under contract. The producer is then paid for the availability of its capacity and for the used energy at prices determined in the contract. Many countries have chosen the solution of long-term contracts to reward the peaking units. France, New Zealand or the Scandinavian countries are some of these countries. The generation capacity that must be contractualised is determined after a consultation between the government, the regulator and the TSO. Producers are then selected through a competitive tender.

The long-term contracts however have a main drawback similar to the drawback of the integrated strategic reserve (Finon, Meunier, & Pignon, 2008). Indeed, the TSO may ask some its contractors to run while it is not needed. As a result, the market would be distorted by an overuse of long term contracts and would exclude of the merit order some generation units that are cheaper than those related to long-term contracts. To limit this impact, many countries have chosen to set a threshold price below which the TSO cannot dispatch these generation units with such a long-term contract.

The long term contracts seem more conducive to a demand response program. A market participant other than the TSO may build and sell the demand response program toward customers and toward the TSO. However, the long-term contracts may be very difficult to implement because the curtailment capacity will continuously vary over time with the dynamics of the customer base. If the demand manager wants that its whole curtailment capacity is always remunerated, he would then have to renegotiate regularly existing contracts with the TSO or sign new ones. The main risk is misalignment of the customer base and demand response capacity. If the customer base provides a curtailment capacity smaller than the contractual capacity, the demand response operator can no longer honour its commitments to the TSO. If the customer base provides a curtailment capacity bigger than the contractual capacity, the demand response operator undervalues its ability to modify demand levels.

One solution for the demand manager[25] is to build its contract with the TSO with a degree of flexibility in connection with the development of its customer base. But the rationale of the TSO is to search for firm commitments to address the coverage of the peak time. So what would be the TSO willingness to commit on a variable volume of demand response to ensure long term peak capacity? Objectively, such a contract between the TSO and the demand manager would only be for the TSO a minor tool among others that are more conventional like peak generation to cover load at peak time.

4.1.2 Demand response and capacity payment

In different countries, capacity payments schemes have been tested to fix the issue of the generation missing money. England and Wales before the reform of NETA in 2000, Spain, New Zealand and several Latin American countries (Argentina, Chile, Colombia or Peru for instance) have adopted a capacity payment solutions with very contrasted results. We will review these experiences and determine how they can help us to go a step further in our analysis of demand response solutions.

In England and Wales before the reform of NETA in 2000 for instance, a producer was paid by the formula depending on its availability for the considered period:

$$\text{Revenue} = \text{blackout probability} \times (\text{VoLL} - \text{SMP})$$

where
VoLL = Value of Lost Load
SMP = System Marginal Price

This payment has drawn sharp criticism on each component of remuneration (Staropoli, 2001; Perez, 2002). Indeed, some producers had incentive to withdraw capacity in order to increase the likelihood of stress or blackout of the system and thus their compensation. Similarly the level of the VoLL is important. The VoLL is set either in an administered manner with the risk of associated lobbying or with a market mechanism with the risk of price manipulation.[26] For all these reasons, this system of capacity payment has been abandoned in the great reform of the English pool in 2000. Other countries implement a slightly different capacity payment mechanism. In Spain and in some countries in Latin America (Argentina, Chile, Colombia, Peru), the capacity payment is made ex post. The formula used is as follows:

$$\text{Revenue} = \text{available generation capacity} \times \text{fixed price}$$

The price for capacity may vary seasonally or remain fixed. This system has led to conflicts on the determination of the actual available capacity of a hydroelectric plant. But above all, having to be available has had perverse effects. Indeed, some producers are encouraged to make bids very high on the spot market so that they are sure they will not be dispatched but they will and get paid for their notional capacity. Old generators can then have a wealthy second life while not running with such a bidding strategy getting pay for capacity (MW) but not for generation (MWh).

Under the assumption that demand response is eligible to capacity payment, this mechanism is more suitable to allow the development of demand response. As for the long-term contracts, a market participant other than the TSO may build and sell the demand response program toward customers and toward the TSO with a price determined in advance. However, with the capacity payment, there is no long term commitment on the volume. The problem of commitment with the TSO on a fixed demand

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[25] A second solution for the demand manager would be to lock its customer base with long term contracts to avoid any variation of demand response capacity, imposing exit costs for example. The previously raised problem is thus solved once the customer base is established. But the phase when the customer base is being constituted will always be problematic and the competition concern can be great.

[26] Besides, the level of SMP in the English-Welsh pool was also said to be more the result of market power than the result of a competitive game (Evans & Green, 2004).

response capacity here vanishes. The demand manager has a strong incentive to invest without having to manage the effects of changes in its customer base on its relations with the TSO. However considering the risk that the TSO undergoes in such a situation, it is unlikely that demand response be let eligible to capacity payment.

4.1.3 Demand response and capacity market

In half of the power markets of the USA, each electricity supplier must be able to demonstrate to the Independent System Operator (ISO) that it can withstand all the demands on its customers in case of peak time plus a certain margin (Finon & Pignon, 2008). It has three tools to achieve this goal: 1° its own generation capacity, 2° the long-term contracts it has with other producers in the area of its ISO, 3° some additional generation capacity rights that he may acquire or exchange on a dedicated capacity market.

Indeed, capacity markets have been introduced in some USA regions. The producers can exchange capacity credits on a market and are then compensated for the capacity they have (in addition to their revenue from the energy market for their output). However, if a producer is not able to produce in case of need of the capacity for which he was paid for, he will face very heavy penalties incentives. Overall, these capacity markets, once cured effectively of their infancy problems[27], proved to be effective when mature. The capacity market is essential for the generators in the USA. Their revenue from the capacity market is such that without this revenue for their capacity, a lot of producers would have disappeared (Joskow, 2008).

Experience with forward capacity markets since 2007 in PJM and New England demonstrates that these markets have been very efficient in driving investment in demand response and energy efficiency (figure 5). In New England, demand response has increased from about 0.6 GW in 2007 to more than 3 GW in the 2010 auction for capacity in 2013 (for a peak demand of 28 GW in 2007). A similar trend has been observed in the PJM capacity market where demand response has increased from 1.5 GW in 2007 to more than 14 GW in the 2011 auction for capacity in 2014 (for a peak demand à 145 GW in 2007).

At the EU level and at the Member States level, the need for a capacity market is debated without clear conclusion up to now (Finon & Pignon, 2008).

To our understanding, the capacity market is the solution that fits the best to the requirements for the demand response program in an all market context. Indeed, the demand manager acting on the capacity market can adjust its volume with the dynamics of its customer base. However, the response rate of customers to the curtailment signal still remains a problem. For a non-controlled demand response program, this response rate can be low. Consequently, the demand manager can never be paid for the full management capacity he has.

5. Conclusion

In this paper, we assumed that demand response for small consumers could be a competitive activity. And we then wondered which market design (if any) could permit the merchant development of demand response and smart metering. We answered this question considering the similarities (as for investment, use and economic function) between peak generation and demand response and the difficulties experienced at the international level by peak generation for its revenue in a pure market configuration and the solutions proposed by the electricity markets.

[27] Roques (2008) showed that they could be volatile, disconnected from the energy market and focused on the short run while related to long run with investment.

Studying the matching between the incentive mechanisms implemented to ensure sufficient peak generation investment and the specificities of demand response, we find that the capacity market is the solution that fits the best to the requirements for the demand response program in an all market context. This is because it provides flexibility to the demand response operator while ensuring a given capacity level to the TSO.

The study of the development of demand response program in the USA where capacity markets are implemented confirms that demand response can develop in a competitive way when the market design is adequate. Demonstrating that demand response can develop without regulatory action with an adequate market design leads also to the conclusion that demand response and smart metering can be competitive activity under the conditions that an adapted market design is implemented.

We see four further research directions that could complete our work. First, the effect of a major participation of demand response in the power market could be integrated to have a more accurate evaluation of the revenue for demand response operator. Second, strategies could be developed to maximise the revenue of a demand response operator with temporal arbitrage between the day-ahead and real time markets. Besides, we could extend our analysis to the revenue that a demand response operator could receive while doing load shifting integrating the rebound effect appearing when curtailed load gets back into operation. At last, an important issue to be considered is the implementation of capacity market in an interconnected system such as the European one. The national capacity market architectures should be compatible in not harmonised and the interconnectors properly treated so that the capacity markets incentivise the investors to effectively develop new generation and demand response capacity in the cheapest manner.

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